University of Hawaii at Manoa

Hawaii Institute of Geophysics

MEMORANDUM

January 8, 1990

Memo To: W. Coops
Managing Director
NELH/Host Park
220 S. King St. Suite 820
Honolulu, HI 96813

From: Donald Thomas

Subject: Information requested by DLNR

Having reviewed the DLNR request for information, it would appear that the attached summary of shut down program for HGP-A would provide the majority of the information that they were requesting in Item 1. You might also add to that memo that the water level was checked in the well on December 15, when it was found to be approximately 720 ft below ground level, and again on January 4, when the water level was found to be about 280 ft below ground level.

At its current rate of recovery, I think that we can schedule a downhole temperature and pressure survey in mid-February. By this time, the water level should be near the surface and will allow us to get a complete temperature profile. I will also attempt to arrange for a downhole caliper log of the well during this same time frame as well.

Should you need additional information to supply to DLNR, please contact me at your convenience.

DOWALD REVIEW OF HGP-A WELL CONSTRUCTION HISTORY AND INTEGRITY

The purpose of this report on the geothermal well HGP-A, located in the Kapoho, Puna, Hawaii, is to review the construction and integrity of the well. Pertinent information from the HGP-A well record, daily field reports, Completion Report (9/76) and Workover Report (2/81) was used to draw conclusions about the integrity of the well.

The Hawaii Geothermal Project was organized to focus on identification, and generation and utilization of geothermal energy on the Island of Hawaii's Kilauea East Rift Zone. The geothermal well HGP-A was drilled by the University of Hawaii in 1976 to accomplish this goal.

The start of drilling activity was December 10, 1975 and the initial well completion date was June 24, 1976. The drilling rig was finally demobilized on September 16, 1991.

HGP-A was drilled to a depth of 6,435 feet, had a maximum temperature of 680° F and produced up to 3 MW of electricity between 1983 and 1989.

The following is a list of well construction problems from December 10, 1975 to September 16, 1991:

- The primary cement used to construct this well is similar to API Class A cement which is recommended for use in oil wells from 0 to 6,000 feet when special cement properties are not required. Class A cement is not high temperature resistant and has poor sulfate resistance.
- Less than satisfactory primary cement quality, due to improper operation of the cement equipment, was used to cement the 13 3/8-inch and 9 5/8-inch casings strings.
- The 9 5/8-inch casing had lack of primary cement bond from 40 to 220 feet and from 320 to 868 feet.
- The primary 13 3/8-inch annular cement settled another 8 feet and had to be brought back to the surface on July 9, 1976.

  Note: Substantial lack of cement bond in the 13 3/8-inch casing annulus can be inferred due to the annular cement settling 8 feet after a top job was done 4 months earlier and the primary cementing equipment not operating properly. A cement bond log was not run on the 13 3/8-inch casing string.

- The 9 5/8-inch N-80 grade casing was not adequate for the concentrations of hydrogen sulfide encountered and the casing couplings are only reliable to 280° F.

- Perforate and cement squeeze jobs on the 9 5/8-inch casing in May, 1976, did not prevent the annular cement from deteriorating and fluids to migrate up the annulus.

- In October of 1979, the 7-inch solid liner, used to seal off and protect the 9 5/8-inch casing from further exposure to geothermal fluids, developed a lack of primary cement bond from 2500 to 2900 feet. Therefore, a perforate and squeeze job was performed on the 7-inch solid casing.

- The perforation and cement squeeze jobs performed on the solid 7-inch casing at 2963 - 2975 ft. and 2530 - 2533 ft. increase the probability that geothermal fluids will breakdown the cement at these entry points and migrate up to the 9 5/8-inch casing shoe located at 2216 feet.

- In January of 1991, a leak was discovered in the 7-inch solid liner at 2530 feet. The cement had apparently deteriorated where a perforate and cement squeeze job was previously performed.

<u>Completed Well Construction (see Figure 1. Page3 for original well construction)</u>

30-inch conductor pipe cemented from surface to 8 ft.

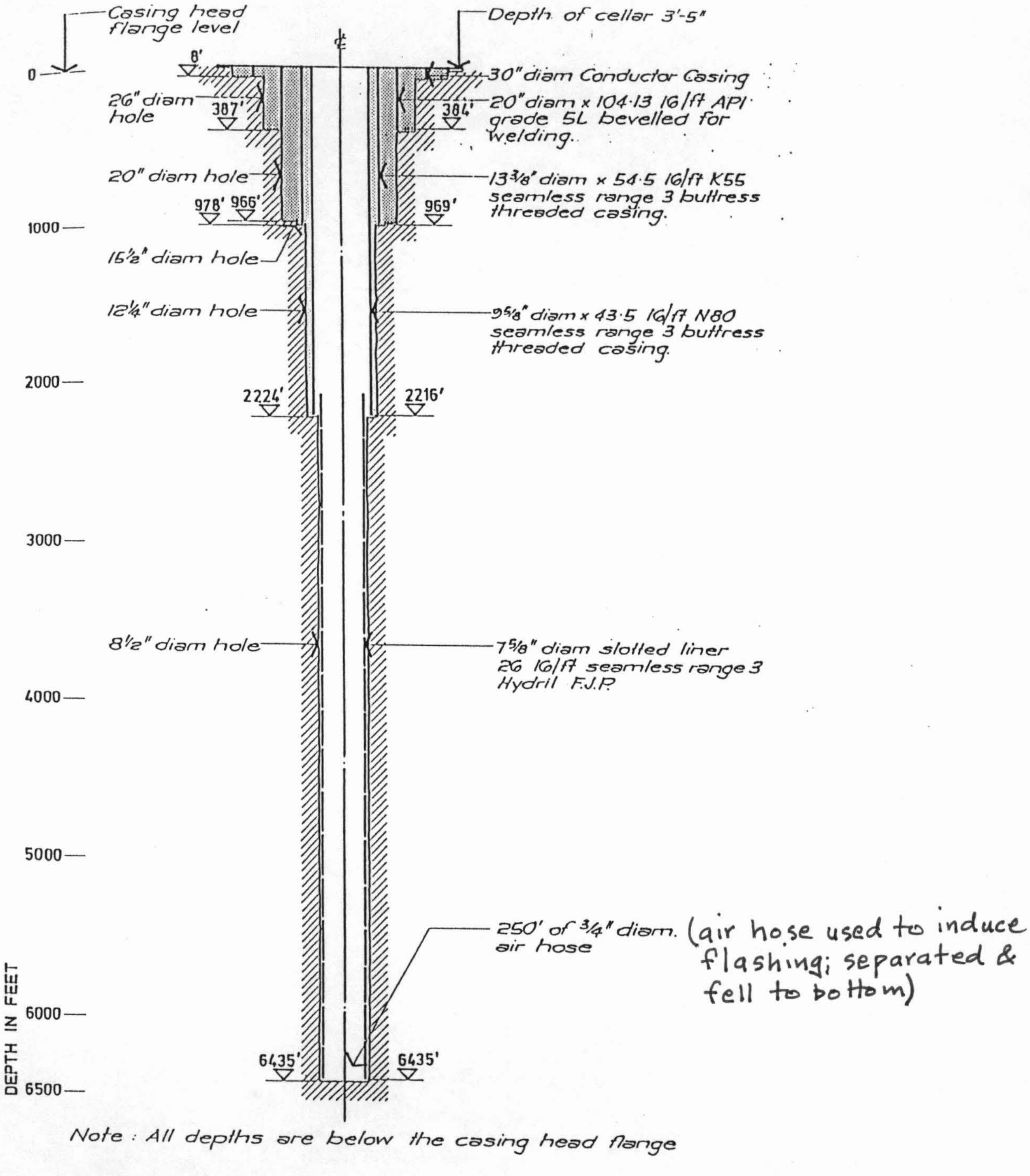
20-inch , 81.10 lb./foot, (no grade or rating listed) cemented from surface to 384 feet.

13 3/8-inch, 54.5 lb./foot, K-55 grade cemented from surface to 969 feet. 2,730 psi minimum internal yield pressure (MIYP).

9 5/8-inch, 43.5 lb./foot, N-80 grade cemented from surface to 2216 feet. 6,330 psi (MIYP).

7-inch slotted production liner, 23 lb./foot, K-55 grade placed on bottom of open hole from 2116 to 6400 feet (about 100 ft. inside 9 5/8-inch casing).

Figure 1. Diagram of Initial Completion of HGP-A Well
(from 1976 HGP-A Well Completion Report *)



* See page 14 for current well construction diagram.

Installed during 1979 Workover (see Figure 2, page 14):

7-inch solid liner, 26 lb./foot, K-55 grade from surface to 2,921 feet, attached to 7-inch slotted liner. 4,980 psi MIYP.

Note: The 20-inch and 13 3/8-inch casings used to construct the well have adequate strengths for the pressure and temperature encountered. However, the 9 5/8-inch Grade N-80 casing material is not intended for use in wells producing relatively high hydrogen sulfide concentrations and the casing couplings used on the 9 5/8-inch casing are rated as only reliable to about 280° F.

Cementing

Initial Cement Type:

The cement used to construct the well was ASTM C-150-71, Type I, similar to API Class A cement which is intended for use in oil wells from the surface to 6000 feet with static temperatures of 60° F to 170° F while drilling and when no special properties are needed. The recommended slurry weight is 15.6 pounds per gallon. API Class A cement has poor sulfate resistant qualities.

At the time of cementing, the use of a retarder was not justified, based on a static temperature of about 134° F during drilling at 2,200 feet.

General Method:

The cement was aerated and transferred by compressed air to a small tank where an air entraining agent was added. 2 percent by weight of Bentonite was added manually to the grout at a

Halliburton jet mixer to which water was added. A commercial air entraining agent was used to entrain an estimated 2 to 3 percent of air. The cement was then pumped down the well.

All cementing jobs, except the 30-inch conductor pipe, were performed by pumping cement down through the drill pipe, which is attached to a receptacle above the casing shoe.

The cement is pumped around the bottom of the shoe and up the annulus (space between the casing being cemented, and the formation and outer casing) to the surface.

Cement returns from the inside of the drill pipe to the casing annulus at the surface is the most desirable situation. If the annular cement should recede during hardening, then cement will have to be placed down the back side of the casing being cemented by use of a tremie pipe.

Cementing of 20-inch surface casing:

January 31 and February 3, 1976:

Light weight cement (10.4 pounds/ gallon) followed by heavy weight cement (14.2 pounds/gallon) was used to cement the 20-inch casing string. No return of heavy weight, light weight or water was obtained on the initial cement job. Water was then pumped down the annulus to flush the weak cement in the lost circulation formation.

Later, a core of poor quality cement was retrieved at 54.5 ft. in the annulus. Poor quality, unconsolidated cement was then flushed out with high pressure water followed by ten minutes of pumping cement with full returns to the surface.

Cementing of 13 3/8-inch casing:

February 28, 1976:

Light weight cement (11.5 pounds/ gallon) followed by heavy weight cement (13.9 pounds/gallon) was used to cement the 13 3/8-inch casing string. Initially, good returns were obtained at the surface. Circulation was then lost briefly when the heavy weight cement should have reached 966 feet. Circulation then was lost again while cement in the drill pipe was displaced with water. Cement settled at about 40 and 50 feet in the annulus and had to be backfilled.

The cementing equipment had considerable difficulty operating properly and produced a less than satisfactory grout quality.

NOTE: **THE 13 3/8-INCH ANNULAR CEMENT SETTLED ANOTHER 8 FEET AND HAD TO BE BROUGHT BACK TO THE SURFACE ON JULY 9, 1976.**

Cementing of 9 5/8-inch casing:

April 1 and 2, 1976:

Light weight cement (10.4 pounds/ gallon) followed by heavy weight cement (13.4 pounds/gallon) was used to cement the 9 5/8-inch casing string. The drillers didn't get a return of the light weight cement or heavy weight cement. The annulus was flushed out with water then backfilled with the same volume of heavy weight cement, but with a density of 13.9 pounds per gallon. Still no returns were evident.

The drillers then tried to pressure-up on the cement in the annulus, but it was not possible. Annular cement samples retrieved earlier showed that the initial cement had set up. Grout was then batch mixed and pumped down the annulus, but the pumping equipment wasn't working properly and 43,610 pounds of cement were consumed during mixing, which reduced the density of the cement. It was suspected that air locks had formed in the casing annulus.

Due to these cementing problems, it was decided to lift the wellhead in order to pour cement down the annulus, but when the wellhead was lifted the annulus was found to be full. The equipment was cleaned up and worked proceeded on fitting the new wellhead.

<u>Perforating, Testing and Cementing</u>

A casing bond log (CBL) was run on the 9 5/8-inch casing on April 25, 1976, from surface to 2,230 feet. The CBL was interpreted to indicate a lack of bond and therefore essentially a lack of cement from 40 to 220 feet and 320 to 868 feet.

Perforation, Testing and cementing operations began on May 24, 1976 in an attempt to remedy the absence of cement bond in the 9 5/8-inch casing.

A cement plug was set in the 9 5/8-inch casing from 1,091 to 1,191 feet. Electronically detonated charges were exploded in contact with the inside of the 9 5/8-inch casing, each producing a 5/8-inch diameter hole without penetrating the 13 3/8-inch casing.

The 9 5/8-inch casing was perforated 31 times from 24 to 842 feet. After perforating each suspect area, annular circulation behind the 9 5/8-inch casing and between perforations, was attempted by placing a Retrievable Test Treat Squeeze (RTTS) packer below the test area and pressuring-up on the area.

The only areas of perforation that achieved satisfactory casing annular circulation were between 54 and 172 feet.

<u>May 29, 1976:</u>
Cement was squeezed into the annulus in 2 stages from 172 to 153 feet and from 153 to 54 feet.

After waiting for 19 hours, the cement in the 9 5/8-inch casing was drilled out and the RTTS packer was run in to pressure test the cement squeeze job. Both stages from 54 to 172 feet were found to be leaking. The space above the RTTS was flushed with high pressure water and calcium chloride (accelerator) cement was squeezed into the perforations again. After 24 hours, the cement squeeze area passed the 1200 psi pressure test (details of this pressure test were not recorded).

<u>May 30:</u>
A significant improvement was interpreted when a CBL was run again from 0 to 2200 feet, but doubt still remained about 3 small areas. These small areas were perforated to vent any liquid that

might cause further damage to the well when heated up (the Completion Report does not identify these areas).

June 1:
The cement plug at 1,091 feet was drilled out and work proceeded to run a 7-inch diameter slotted liner.

June 4:
The 7-inch perforated liner was installed, but a casing caliper log was not available, so the caliper log was omitted.

June 6:
Started completion testing with original well construction, page 3.

From July 1976 to November 1978 the well was tested a number of times; testing included a 40 day flow test.

Before the flow test in November, 1978, the wellhead pressure (WHP) during shut-in periods was about 140 psi (according to the Workover Completion Report, February 1981) and the temperature profile was low until it reached the 9-5/8" casing at about 2200 ft., but after the November flow test, the static WHP began to increase gradually.

By January, 1979, the well had to be vented daily to keep the WHP below 500 psi. Also, when a temperature survey was run on 3/12/79 and the resultant profile was compared with an earlier temperature survey run on 6/6/78, the graph(see Figure 2. Page 8) showed a dramatic rise in temperature, especially in the section from 1450 ft. to the bottom of the 9-5/8" shoe at 2200 ft.

Also a methane gas cap formed during the static condition that was not present prior to the flow test in November, 1978. Note: methane in the well is produced from the degeneration of lubrication products used on the drill pipe and casing during drilling activities.

- **The anomalous wellhead pressure increase and dramatic rise in temperature profile prompted the University of Hawaii to run diagnostic tests to determine the mechanical integrity of the well.**

- **A caliper log (0 - 2100 ft.) and cement bond log (350 - 2106 ft.) were run in May, 1979 to determine whether there was a break in the casing or the cement bond had deteriorated.**

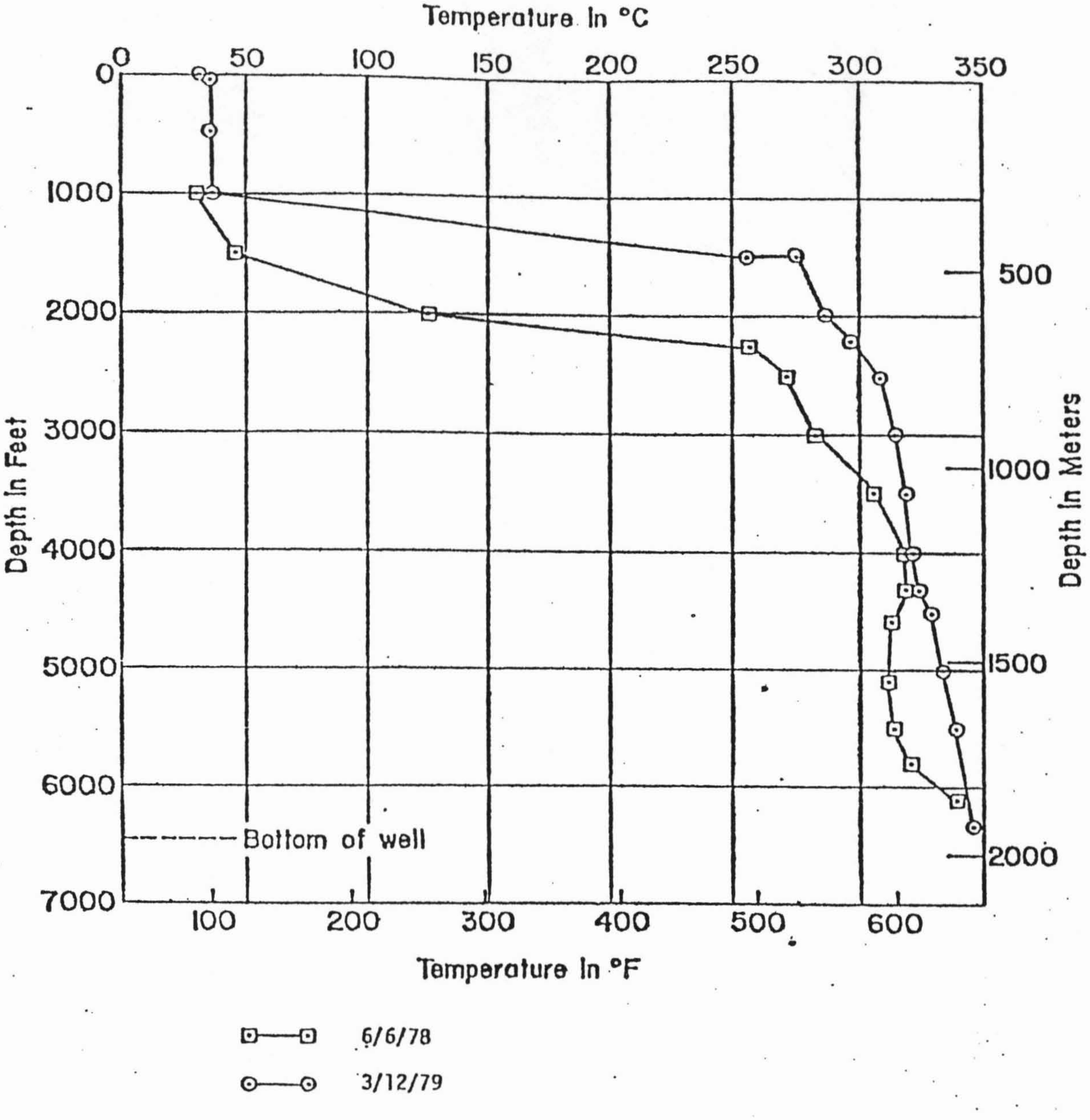


Figure 2. Temperature Profiles of HGP-A Well
(from HGP-A Well Workover Completion Report, 1981)

The caliper log showed no apparent break, but the cement bond log was interpreted to show substantial deterioration of the cement bond.

The decision was made to perforate and squeeze with high temperature cement to improve the integrity of the well. A modification permit for a well workover was issued by DLNR in September, 1979.

Workover Summary

<u>September 15, 1979:</u>
Commencement of workover program.

<u>September 16:</u>
The 9-5/8" casing was pressure tested with a retrievable plug set at 2000 feet and RTTS tool set at different depths failed to reveal any significant leaks.

<u>September 18:</u>
Class G cement with 40% silica flour and 0.5% CFR-2 (low water loss additive) plug was set at about 3088 ft. to prevent the well from producing geothermal fluids while the perforate and squeeze job was performed.

<u>September 19:</u>

1. Set an 81 linear foot second plug (same mixture as first) on top of first cement plug.

2. The top section of original 7" perforated liner was removed from 2116 to 2921 feet.

<u>September 21, 1979:</u>
HOWCO retrievable bridge plug was set at about 2000 feet.

A series of perforate and squeeze jobs were performed above the 9 5/8-inch shoe (2216 ft.) and below 13 3/8-inch shoe (966 ft.):

9/21/79	2150 to 2152 ft.
9/22/79	2110 to 2112 ft. 1650 to 1652 ft.
9/23/79	1250 to 1252 ft. 970 to 972 ft.

Note: After each interval is perforated and before cement is squeezed, a formation breakdown pressure test is performed on each interval (see Table of HGP-A Well Tests and Remedial Work, page 13). The low formation breakdown pressure indicates that the cement outside of the casing had deteriorated so that well fluids migrated on the outside of the casing. The pressure remains low because fluid is able to escape into voids in the cement then into the formation.

The drillers had difficulty retrieving HOWCO bridge plug. It appeared that the 9-5/8" casing had come apart or gone out of alignment at about 2147 ft. After a considerable amount of drilling and milling the plug was retrieved.

<u>September 27:</u>
Cement bond log run showed that squeeze operations had improved the bonding, except at about 1650 ft.

<u>October 2:</u>
Performed a perforate and squeeze job from 1420 to 1422 feet (half way between squeeze job at 1250 and 1650 ft.).

<u>October 3:</u>
Perforated 7-inch slotted liner from 2963 to 2975 feet and set 7-inch RTTS at 2930 feet and broke down formation at 2000 psi.

<u>October 4:</u>

1. Cement bond log inside 9 5/8-inch liner showed the last squeeze job substantially improved bonding between 1200 and 1500 ft.

2. 7" 26 lb./ft K-55 stage was cemented from 2921 ft. (where perforated 7" liner was cut-off) to surface.

<u>October 12, 1979:</u>
Cement bond logs run on solid 7" from 2968 to 2000 feet showed incompetent cement bond from 2500 to 2900 ft.
Performed perforate and squeeze jobs on solid 7" casing from 2530 to 2533 feet.

<u>October 14, 1979:</u>
Final cement bond log run from surface to 2990 ft. showed over 80% bonding on almost the entire string.

October 15:
New wellhead completed on 7" casing and cement plug drilled out.

October 17:
4-1/2 hour flow test showed production was the same as before the worker.

October 18:
Rig released.

Workover was followed by nearly 8 years of production

Dec. 11, 1989:
A decision was made to shutdown the well due to growing controversy over the Hawaii Geothermal Project and resultant political pressure.

Feb. 9, 1990:
Temperature survey run showed no apparent well casing integrity problems.

July 10:
Dismantled power plant.

Nov. 16:
Attempted to run a caliper and temperature survey when an obstruction was encountered at 2,133 feet. Apparently silica scaling had built up in the well bore.

Dec. 17:
Well modification permit issued to clear obstruction at 2133 ft.

Jan. 18, 1991:
Tried to run a packer in the well, but the rubbers on the tool were destroyed due to the rough condition of well.

Jan. 22:

1. Ran casing scraper to 3000 ft. to alleviate casing scaling/roughness problem.

2. Cement bridge set at 2892 ft.

3. Set packer and pressure tested casing - leak found at about 2530 feet in the 7-inch solid casing.

   Note: Perforate and squeeze job done at same depth in 1979, i.e. cement had deteriorated where perforation and cement squeeze job performed in 1979.

4. The drillers performed squeeze job at same depth - well took 30 cubic feet of total 45 cubic feet pumped.

5. Applied 1,700 psi pressure to cement (apparent successful squeeze job).

6. Drilled out cement from 2280 - 2540 ft. and prepared to pressure test well.

Jan. 23, 1991:
Pressure tested cement squeeze job after "plug" of cement drilled out - cement squeezed into perforations and behind 7-inch solid casing would not sufficiently hold pressure. Preparing to do another squeeze job at 2530 ft..

Jan. 24:
The drillers tried to do another squeeze job, but the 2530 ft. area would not take any additional cement. The drillers pressured up on the cement and casing to 1200 psi and held the pressure - the pressure did not drop. A decision was made to go ahead with the Heat Exchanger Test and after completing SOH-2, eventually return to HGP-A to do remedial work

Feb. 25:
Coaxial heat exchanger installed and tested down hole.

March 4:
Coaxial heat exchanger test complete.

June 10:
Coaxial heat exchanger retrieved - prepared to remove packer tool.

June 11:
Got hold of packer tool and began to retrieve it when a gas bubble rose to the surface. Pumped caustic soda to abate hydrogen sulfide then proceeded with packer retrieval.

June 12:
Crew on stand-by.

June 17:
The drillers continued on stand-by status until further notice due to stop order on all drilling activity.

Sept. 11:
Work resumed on packer retrieval. Well circulated with water to cool the well bore. Hydrogen

sulfide in return water is 18 ppb. Caustic mixed with water and circulated down well to cool and abate well.

Sept. 13:
Got packer free plus one joint out of the well when packer became stuck. Packer eventually worked free and the well was shut in.

Sept. 14:
Cleaning well.

Sept. 15:
The drilled rigged down the drill rig in preparation to move rig to SOH-1 location.

Sept. 16, 1991:
The drillers completed rigging down and the rig was moved to the SOH-1 project location.

Recommendation

In the event that a party wants to use the well for monitoring purposes or produce steam from the HGP-A well for generating electricity, we recommend that a number of tests be done to evaluate the well in its current mechanical state.

Mechanical Integrity Testing should include the following:

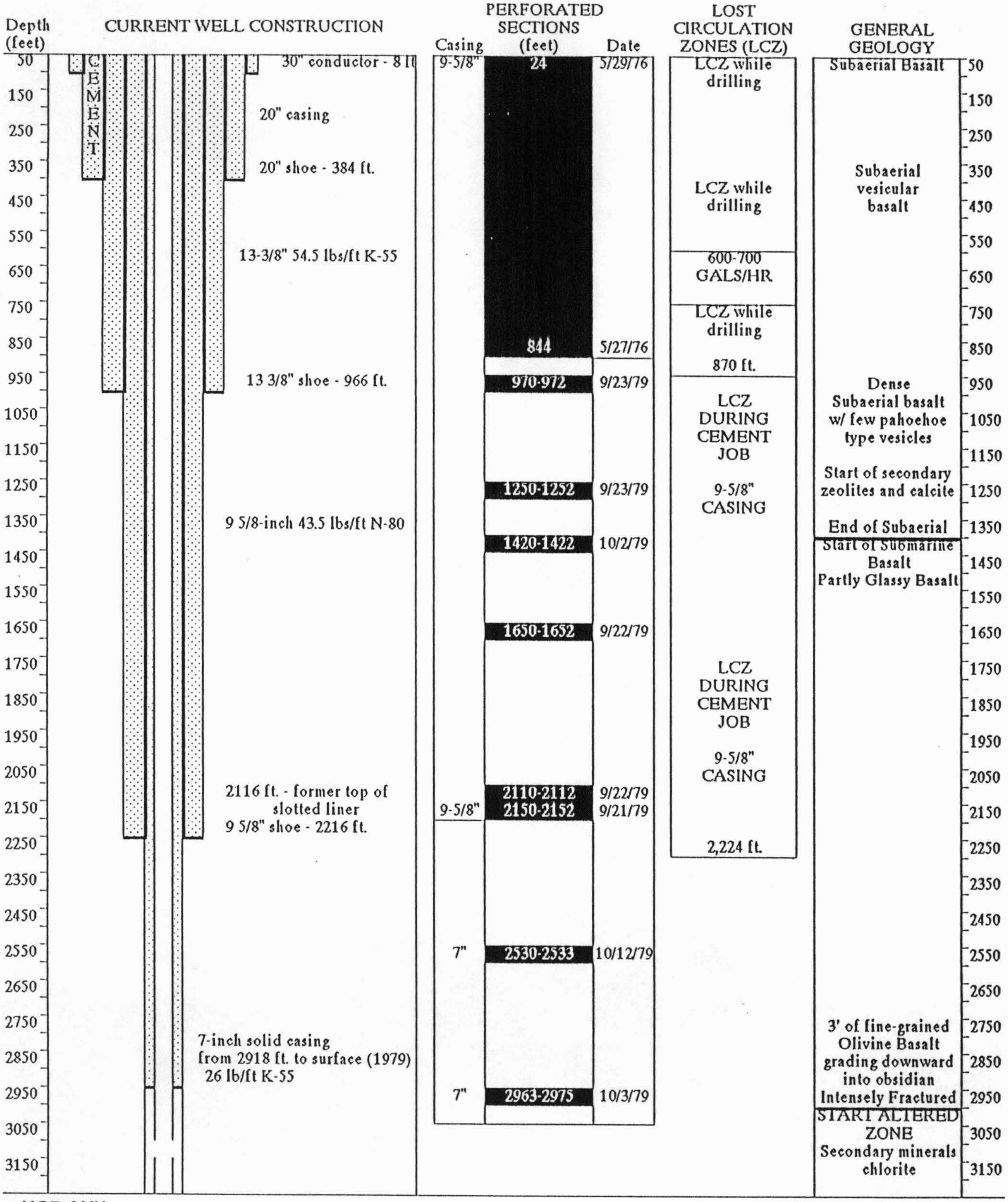
- Pressure and temperature log.
- 100 to 120 arm caliper inspection tool.
- Cement bond log for 7-inch solid casing from 2216 to 2918 feet.
- 7-inch solid casing pressure test.
- Other applicable methods as determined by DLNR.

HGP-A Well Tests and Remedial Work

Date	Perforation Interval (feet)	Depth RTTS Set (feet)	Formation Breakdown Pressure (psi)	Type of Log or Survey	Interval Covered (feet)	Remarks
4/25/76					0-2200	0-234 ft.= No Bond 234-330 ft. = Excellent Bond 330-868 ft. = No Bond 868-970 ft. = Excellent Bond 970-2200 ft. = Fair to Excellent
4/25/76				Temperature	100-4300	Normal temperature profile.
4/27/76				Caliper	2225-3800	Log run on 7-inch slotted liner.
5/27/76 to 5/29/76	24-842	Various Depths	Not Available			9 5/8" casing perforated 31 times. Only sections from 54-172' developed satisfactory circulation in 9 5/8" annular space for cement squeeze.
5/29/76				Cement Bond	0-2200	* HGP-A Completion Report states that a significant improvement was interpreted.
3/12/79				Temperature	0-6300	Temperature survey profile shows rise in 493 degree F level in 9 5/8" casing from 2200' to 1450'.
5/20/79				Temperature	100-2400 ft.	236 deg. F at 2400 feet.
5/20/79				Caliper Log	0-2100 ft.	Some pits & corrosion at 34', 766', 960', & 1770' No casing breaks indicated.
5/20/79				Cement Bond	350-2106 ft.	380-756 ft: = Alternating sections of poor to good cement (avg. section length = 22'). 756-876 ft = Poor cement bond. 876-946 ft. = Good cement bond. 946-2100 ft = Very poor to lack of cement bond.
9/17/79				Cement Bond	20-500	* Substantial deterioration of cement bond confirmed.
9/21/79	2150-2152	2165	1000			No leaks detected.
		2075	200			Low formation breakdown pressure showed that fluids migrated on the outside of the 9 5/8" casing.
9/22/79	2110-2112	2015	1500			
	1650-1652	1545	200			
9/23/79	1250-1252	1167	200			
	970-972	880	2500			
9/28/79				Cement Bond	100-2200 ft.	* Improved bonding after perforate and squeeze job except for cement at 1650'.
9/29/79				Caliper Log	2100-2914 ft.	No leaks.
10/02/79	1420-1422	1260	200			Formation breakdown pressure show that fluid migrated through annular cement.
10/03/79	2963-2975	2930	2000	Temperature		Perforation on 7-inch slotted liner.
10/04/79				Cement Bond	100-2200	Casing Bond Log run on 9 5/8" casing showed improved bonding at 1650 ft.
7-inch solid production casing cemented from 2918 ft. to surface and installed into 7" expansion spool and wellhead.						
10/12/79	2530-2533	2576	1200	Cement Bond	2000-2968	* Cement Bond Log on 7-inch solid liner showed incompetent bonding from 2500-2900 ft.
10/14/79				Cement Bond	20-2990	* Over 80% cement bonding on almost entire 7-inch solid casing.
01/22/91				Pressure Test		Cement deterioration found in 7" solid casing at 2530 ft.

* = Cement bond log not available for evaluation; interpretation is from 1976 Well Completion Report
RTTS = Retrievable Test Treat and Squeeze packer

Figure 3. HGP-A Current Well Construction, Perforated and Cement Squeeze Sections, Lost Circulation Zones, and General Geology



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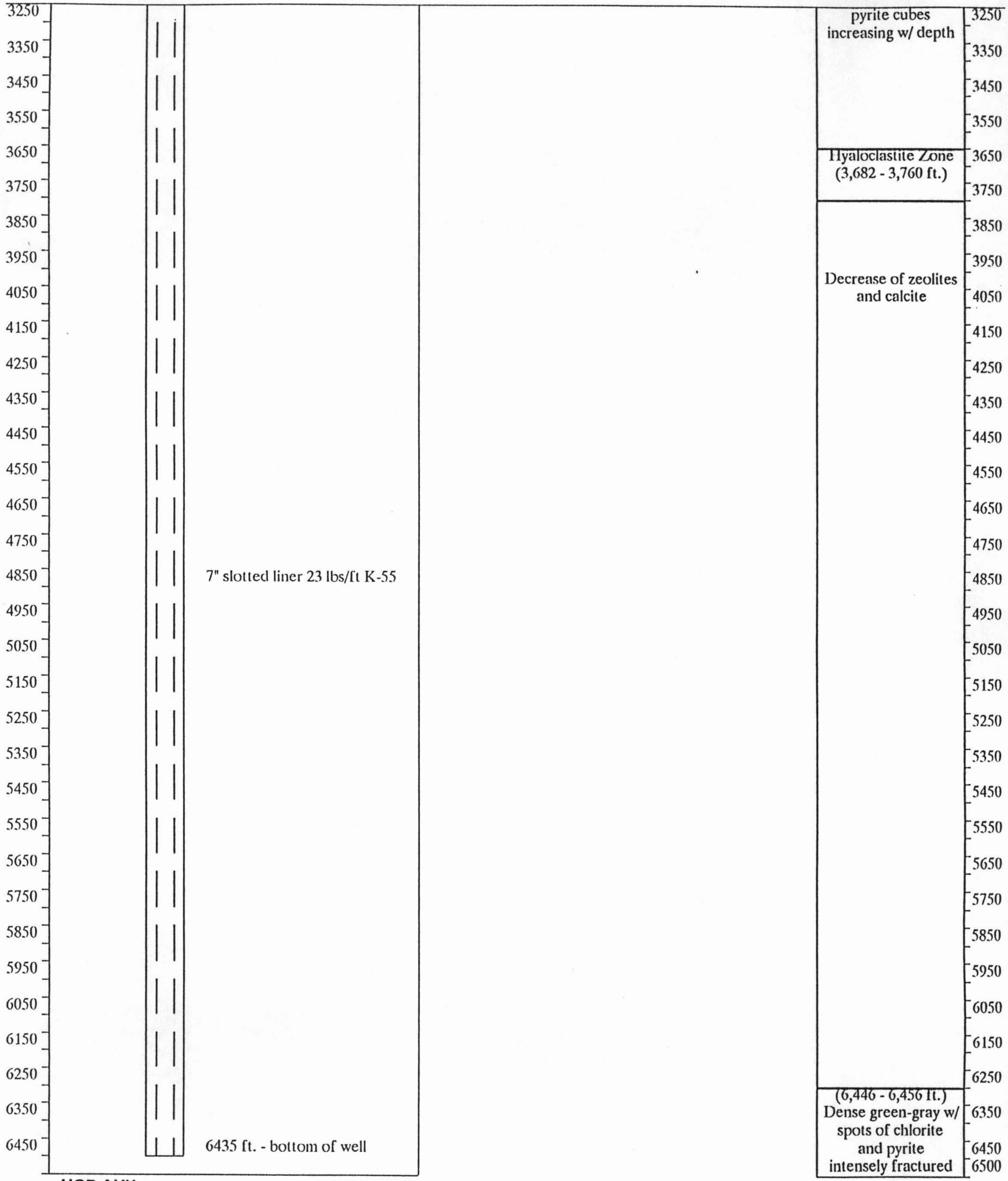
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6450
7" slotted liner 23 lbs/ft K-55
6435 ft. - bottom of well
pyrite cubes increasing w/ depth
Hyaloclastite Zone (3,682 - 3,760 ft.)
Decrease of zeolites and calcite
(6,446 - 6,456 ft.) Dense green-gray w/ spots of chlorite and pyrite intensely fractured
6500

HGP-AHX